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Remediation of CO_2 leakage using pressure gradient reversal method: A numerical modelling study

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Abstract

It has been suggested that injection of brine above the caprock, at a higher pressure than the CO_2 pressure in the reservoir, would create an inverse pressure gradient to reverse the flow direction and increase the solubility of CO_2 in the saline water barrier formed, and prevent or limit leakage. The effectiveness of the pressure gradient reversal (PGR) method as a potential remediation technique for CO_2 leakage from deep saline aquifers was investigated using a realistic 3D reservoir/caprock model. A hypothetical CO_2 storage operation involving CO_2 injection at 1 Mt/year for up to 30 years down-dip of a structure high in the model domain was considered. The brine injection simulation results indicate that the performance of PRG is strongly affected by how early leakage is detected from the start of injection (time-to-detection), which in turns is controlled by the detection threshold, leakage pathway permeability and the distance to the injection well. PRG is more effective the earlier leakage is detected and the closer the leakage location is to the injection well.

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Keywords: caprock leakage risk profiles, CO_2 leakage remediation; pressure gradient reversal; reservoir simulation

1. Introduction

It has been suggested [1] that injection of brine above the caprock, at a higher pressure than the CO_2 pressure in the reservoir, would create an inverse pressure gradient to reverse the flow direction and increase the solubility of

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CO_2 in the saline water barrier formed, and prevent or limit leakage. Furthermore, coupled with fluid management procedures during aquifer storage (saline water extraction and re-injection above the caprock), this methodology can also be used to minimise displacement and migration of native brine, and avoid pressure build up in closed or semi-closed structures. In a more recent study, Reveillere et al. [2] conducted a numerical study on the same phenomenon using an overly simple 3D flow model with flat layers (thus buoyancy-driven lateral migration of CO_2 was absent). They reported that this technique may efficiently stop leakage in a relatively short time or may be effectively used as a preventive measure, while continuing injecting CO_2.

It was thus suggested that, such a procedure could enable fast and relatively low cost mitigation action once a leakage is detected. On the other hand, the results illustrated in the literature are valid for a specific case and the methodology may have limitations which needed to be investigated further through exhaustive analysis of field based properties.

In the research reported here, the effectiveness of the pressure gradient reversal (PGR) method as a potential remediation technique for CO_2 leakage from deep saline aquifers was investigated using a realistic 3D reservoir/caprock model.

2. Modelling of CO_2 leakage through the caprock

2.1. A generic reservoir/caprock model

The chosen model domain measures 36 km x 10 km and includes several faults (Fig. 1a). The depth of target storage formation ranges from 1,082 to 3,484 m across the model domain, dipping considerably. The injection well is located at a location where the storage reservoir is between 1,973 to 2,181 m deep (Fig. 1). The model has a more or less uniform grid block size of 200 m x 200 m in the lateral direction.

The storage reservoir, which has a thickness of approximately 240 m, consists of 6 layers of homogeneous reservoir properties (base case model), but with varying properties across the layers. In particular, the (horizontal) permeability ranges from 4 to 90 mD. The vertical permeability was assumed to be the same as the horizontal permeability. The reservoir/overburden is initially at hydrostatic pressure, and the reservoir temperature is 92 ºC. The overlying formation (caprock) is considered to be impermeable, with a further 60 m thick layer above the caprock, situated at 180 m above the reservoir, which is assigned a permeability of 10 mD (Fig. 1b).

2.2. Potential CO_2 leakage risk profiles through caprock

Reservoir simulation of CO_2 injection at a rate of 1 Mt/year for 30 years from 2012 was carried out to evaluate the plume migration behaviour during injection and after the termination of injection. A pore volume multiplier of 100 was used during simulations to represent the connected pore volume beyond the model domain. It was found that the plume largely stabilised at about 120 years from the start of injection. Based upon this plume migration behaviour, and the tendency to migrate up dip following the formation topography, it is suggested by the authors that the plume footprint may be broadly divided into: a transient region (where the free CO_2 largely has a limited residence time), and a non-transient region (where the free CO_2 residence is more or less stable) (Fig. 2).

Using the generic reservoir/caprock model, an attempt was made to compute and map potential leakage risk profiles, i.e. the total amount of CO_2 that could potentially leak through the caprock, and the leakage time periods, at various locations in both the transient and non-transient regions. To simulate CO_2 leakage through an assumed fracture zone, a leakage pathway is intentionally created by assigning a permeability of between 1 and 10 mD to the column of grid blocks in the caprock between the storage reservoir and the permeable layer above (Fig. 1b). During simulations, the cumulative leakage from the storage reservoir is monitored and injection is terminated when a pre-set leakage detection threshold/limit is exceeded. A detection threshold between 1,000 to 10,000 tonnes of CO_2 was considered here based on the suitability of monitoring methods for detection and quantification of CO_2 leakage from a storage site under favourable conditions at depths of less than 1,000 m [3, 4]. For simplicity, capillary entry pressure was not considered during the leakage simulations.

The time (year) it takes for the leakage to be detected during the simulation, i.e. time-to-leakage detection, referred to for simplicity as the time-to-detection (TTD), maybe computed and it is expected to vary spatially within the CO_2 plume footprint. At each leakage location, the TTD depends on the combined effect of a detection threshold applied and the leakage pathway permeability assigned. Although CO_2 injection is terminated once leakage is detected, leakage is continuously being monitored to obtain a potential leakage profile, namely the total leakage duration and the cumulative CO_2 leakage, at each leakage point. Simulations are stopped at year 2132, some 120 years from the start of injection at year 2012. Examples of computed leakage profiles at 3 different locations, consisting of three grid blocks (P42, P43 and P44) in the transient region are presented in Fig. 2. The leaked CO_2 mass is shown to reach a plateau in the transient region, and leakage would continue for a further period of time withthe total leakage duration being long and positively correlated with the time-to-detection at each grid block.

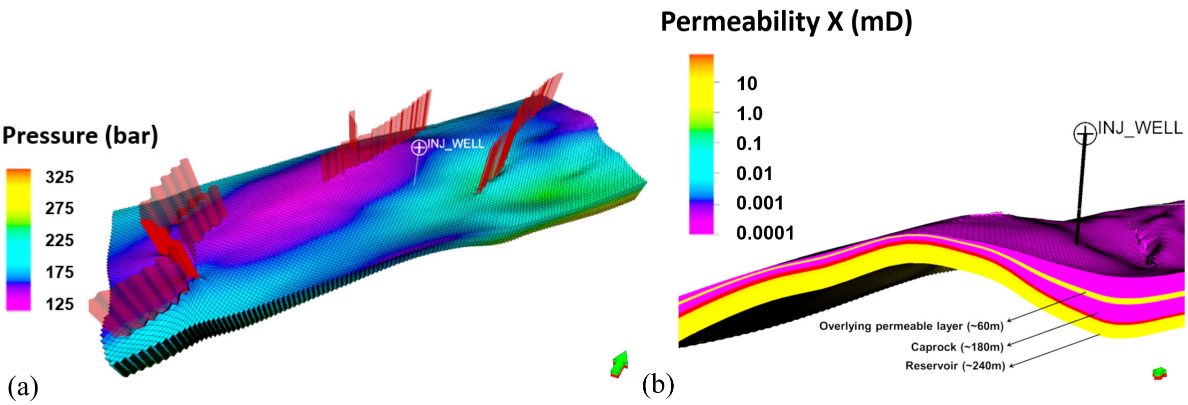


Fig. 1.A generic reservoir/caprock model for simulation of CO_2 injection above a leaking caprockand evaluation of potential CO_2 leakage profiles.

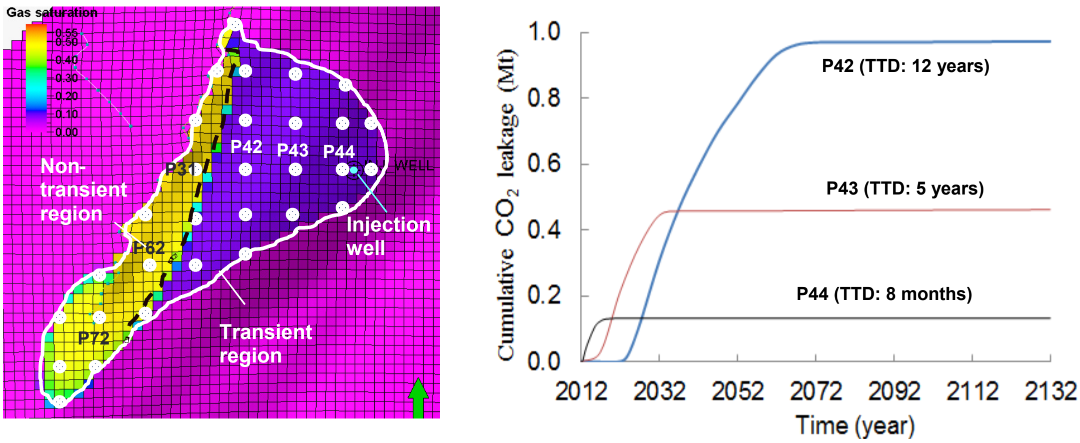


Fig. 2.Computed potential CO_2 leakage profiles at selected points in the transient and non-transient regions, showing distinctive region-wise trends (leakage pathway permeability = 10 mD, leakage detection threshold = 10,000 tonnes).

3. Pressure gradient reversal for remediation - modelling brine injection into an overlying permeable layer

In this section the performance of brine injection into an overlying permeable layer (Fig. 1b) as a potential means for leakage remediation is evaluated through reservoir simulations. In the simulations, brine was injected into the original CO_2 injection well immediately following the detection of leakage and the termination of CO_2 injection. In other words, time which would normally be required for the conversion from a CO_2 injector to a brine injector was not considered. Brine injection into the overlying permeable layer was subject to a constant bottom hole pressure limited to 1.3 times of the hydrostatic pressure to prevent fracturing the reservoir and caprock.

The potential leakage risk profiles for three different leakage locations in the transient source zone have been presented previously in Fig. 2. In this research two of the three leakage blocks, i.e. P44 and P43 (Fig. 2), were selected for conducting above-zone brine injection simulations. The focus of the modelling work was on P44, as it is much closer (200 m) than P43 is (1,200 m) to the injection well. A total four leakage scenarios with different combinations of leakage pathway permeability/detection threshold (Table 1) were considered to evaluate the effectiveness of PGR under different conditions.

Table 1. The 12-month brine injection performance for cases with different combinations of leakage pathway permeability/detection threshold.

		Case 1 (base case)	Case 2	Case 3	Case 4
Detection threshold (*tonnes*)		10,000	1,000	10,000	1,000
Leakage pathway permeability (*mD*)		10	10	1	1
Time-to-detection (*month* / *year*)		8 / 0.67	5 / 0.42	24/ 2	14 / 1.2
Cumulative leakage (*Mt*)	Without PGR	0.13	0.07	0.07	0.04
	PGR for 12 months (% of cumulative leakage without PGR)	0.03 (23%)	0.01 (14%)	0.04 (57%)	0.02 (50%)
Leakage period (*years*)	Without PGR	7	6	15	10
	PGR for 12 months	2.5	2	12	8

3.1. Results for P44 - Case 1

Brine injection commences after the injection of 0.67 Mt CO_2 into the reservoir, when the leakage is deemed to be detected after 8 months of CO_2 injection. Brine injection for different time periods between 4 to 16 months, under a constant BHP (227.5 bar), was simulated to evaluate its performance. The simulated brine injection rates show a general upward trend rising from about 0.75 to 1.25 Mt /year for the four scenarios with different injection (PGR) duration.

Left untreated (no remediation), the leakage would last for about seven years with a total of approximately 0.13 Mt of CO_2 being leaked into the caprock (Table 1 and Fig. 3a). As the brine injection period is increased from 4 to 12 months, the cumulative CO_2 leakage amount is reduced steadily to around 0.3 Mt (Fig. 3a). Moreover, the CO_2 leakage duration is also significantly shortened from 7 years to about 2.5 years by increasing the injection time to 12 months. The results also show that extending the injection time further would only bring a marginal reduction in CO_2 leakage.

As shown in Fig. 3b, there is a prompt, sharp reduction in the CO_2 leakage rate in response to brine injection. This is followed by a varying degree of rebound in the rate if brine injection is stopped prematurely within 12 months. There are two possible factors that may contribute to the decrease in CO_2 leakage rate: 1) injecting brine into the overlying layer results in a reduction in the pressure difference between the reservoir and the overlying permeable layer along the CO_2 leakage pathway; 2) the injected brine may flow downward from the overlying layer to the reservoir through the CO_2 leakage pathway and displace mobile CO_2 around the leakage point.

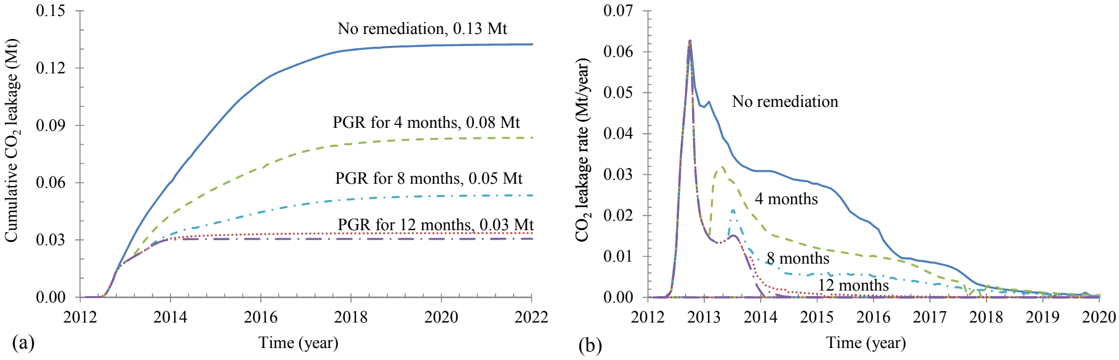


Fig. 3.a) Cumulative CO_2 leakage and b) leakage rate for scenarios with different PGR times at P44 (Case 1).

It is seen in Fig. 4a that injecting brine into the overlying layer not only raises the pressure there, but also increases the reservoir pressure around the leakage block if brine injection continues after 4 months. The sharp decline in the pressure difference in the early stages of bine injection (to ~ 13 bars compared to ~22 bars at hydrostatic pressure level, Fig. 4b) is believed to be mainly responsible for the observed steep rate reduction in Fig. 3b. On the other hand, the displacement of mobile CO_2 away from the leakage block (reflected in the reduction in its CO_2 saturation, eventually to the residual value, Fig. 5) appears to be the dominant cause for the shortened leakage time period.

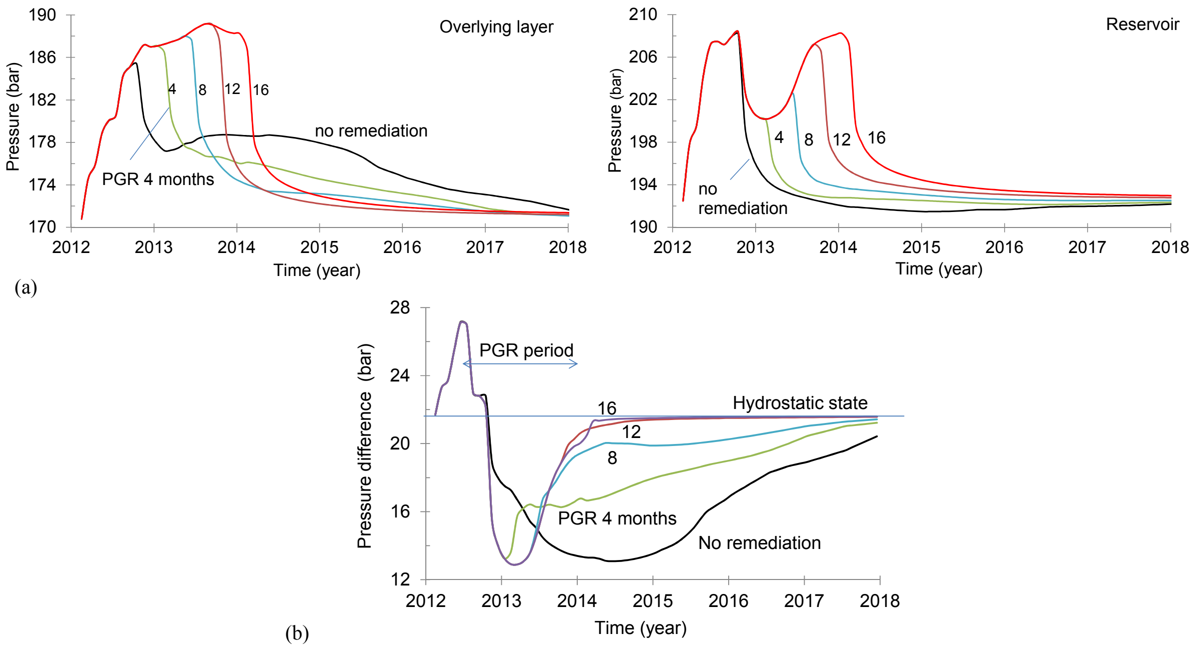


Fig.4.a) Pressure evolution at the leakage block (P44) in the overlying permeable layer and the reservoir over time; b) pressure difference between the reservoir and the overlying layer where the brine is injected.

3.2. Results for P44 – sensitivity to leakage detection threshold and leakage pathway permeability

The unmitigated potential leakage risk profile and the brine injection performance for Case 1 (10,000 tonnes CO_2 leakage detection threshold and 10 mD leakage pathway permeability) have been discussed above. Clearly, a lower detection threshold (other conditions remain unchanged) would lead to earlier leakage detection with associated consequence for the total CO_2 leakage potential. For example, reducing detection threshold from 10,000 to 1,000 tonnes CO_2 (Case 2 in Table 1) would reduce the time-to-detection from 8 to 5 months. In addition, the leakage potential would also be significantly decreased (from 0.13 to 0.07 Mt) (Table 1).

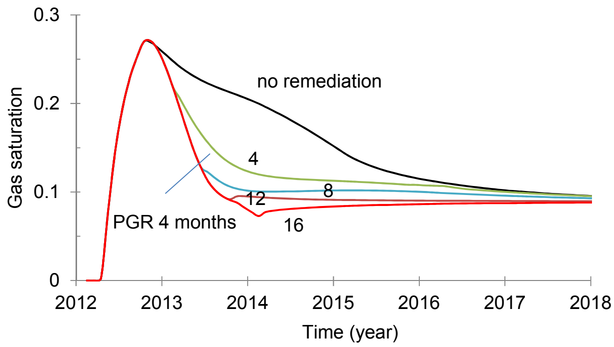


Fig.5.Evolution of CO_2 saturation at the leakage block (P44)at the top of the reservoir.

On the other hand, lowering the leakage path permeability (other conditions remain unchanged) means it would take longer to detect the leakage. For instance, it would take 24 months, rather than 8 months, for the leakage to be detected if the leakage pathway permeability is reduced by one-order of magnitude to 1 mD (Case 3 in Table 1). In other words, 2.4 Mt CO_2 would have been injected, three times as high as that for case 1 (0.8 Mt) at the time of leakage detection. However due to the much lower leakage pathway permeability of 1 mD, the estimated total leakage potential at 0.07 Mt was almost half of that for Case 1 (0.13 Mt).

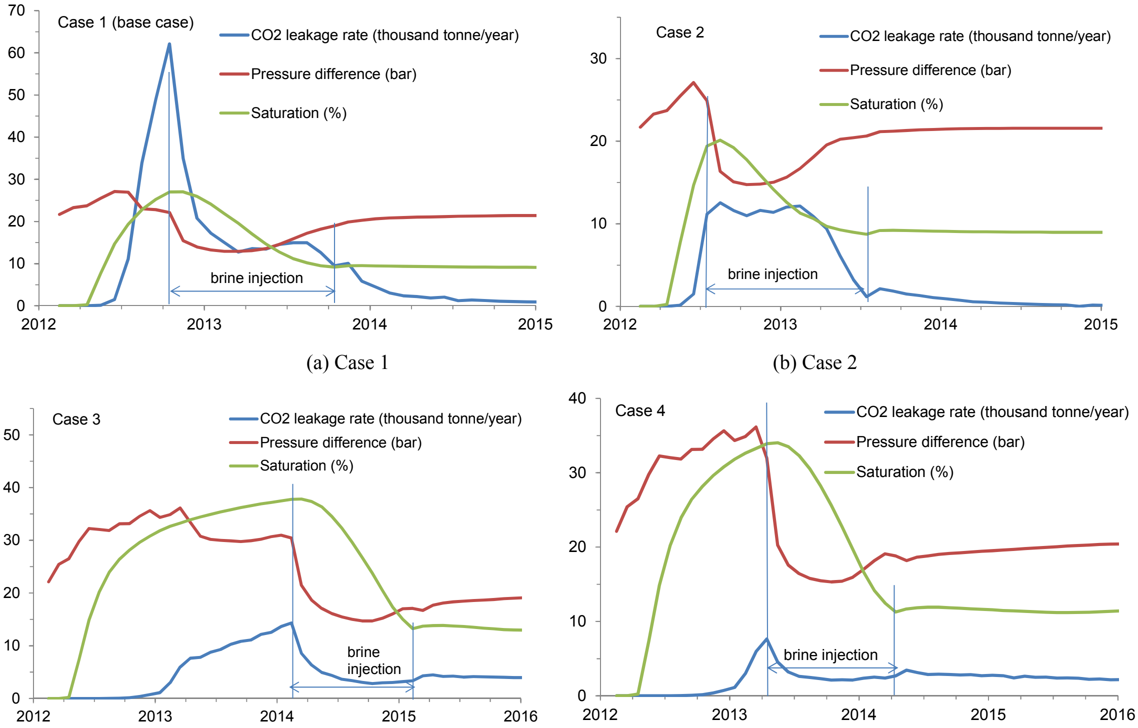
The total leakage potential would further reduce to 0.4 Mt if both the detection threshold and the leakage pathway permeability are reduced by one-order of magnitude (Case 4, Table 1). Comparing Case 4 (time-to-detection = 14 months) with Case 1 (time-to-detection = 8 months), it would appear that the leakage pathway permeability is the more dominant factor, controlling the leakage detection timehere.

It is also noted that CO_2 leakage tends to continue for a considerably longer period of time for the lower pathway permeability cases (15 years for Case 3 and 10 years for Case 4, Table 1). It has been shown in Case 1 that the optimal length of brine injection is 12 months from the standpoint of leakage mitigation performance. In view of this finding, brine injection simulation was carried out for 12 months for the other three cases. The results are presented in Fig. 6 and also summarised in Table 1. The following observations are made.

- The simulated brine injection rates for the four cases display broadly similar trend, rising from an initial ~0.75 Mt to ~1.25 Mt/year.
- As with Case 1, a prompt reduction in the CO_2 leakage rate is also predicted for Case 3 and Case 4, following a sharp drop in the pressure differential between the overlying permeable layer and the storage reservoir (Fig. 6c and d). However, no reduction is observed for Case 2 – the CO_2 leakage rate has reached a plateau over much of the brine injection period (Fig. 6b). This may be partly due to the fact that the leakage rate is already rather low at the start of brine injection compared to Case 1.
- As shown Fig. 7, and in Table 1, above-zone brine injection as a means of leakage mitigation appears to be more effective for Case 1 and Case 2 (leakage path permeability = 10 mD) than Case 3 and Case 4 (leakage path permeability = 1 mD). For example, the reduction in CO_2 leakage potential is estimated to be 77% and 86% respectively for Case 1 and Case 2, compared to 57% and 50% respectively for Case 3 and Case 4.

3.3. Results for P43 – leakage point far from the remediation well in the transient region

At P43, which is 1,200 metres away from the CO_2 injection or the remediation well, leakage is detected in 2017, after 5 Mt CO_2 has been injected into the reservoir. In the absence of any remediation action, CO_2 leakage is forecasted to continue for a further 20 years until 2037 and a total of 0.46 Mt CO_2 would be leaked into the upper permeable layer by then (Fig.8a). According to the model predictions (Fig. 8b), the CO_2 leakage rate would reach a peak (at around 0.037 Mt/year) in 2023, approximately 6 years after the termination of CO_2 injection. As with leakage block P44, brine injection into the original CO_2 injection well was simulated from 2017 following the detection of leakage. It soon became clear that above-zone brine injection, at a rate of over 1 Mt/ year, would be much less effective in mitigating CO_2 leakage from block P43 than from block P44.



(a) Case 1 (b) Case 2

(c) Case 3 (d) Case 4

Fig.6.Cross-plots between CO_2 leakage rate and pressure difference across the leakage pathway and CO_2 saturation at the leakage block (P44) at the top of the reservoir (brine injection for 12 months).

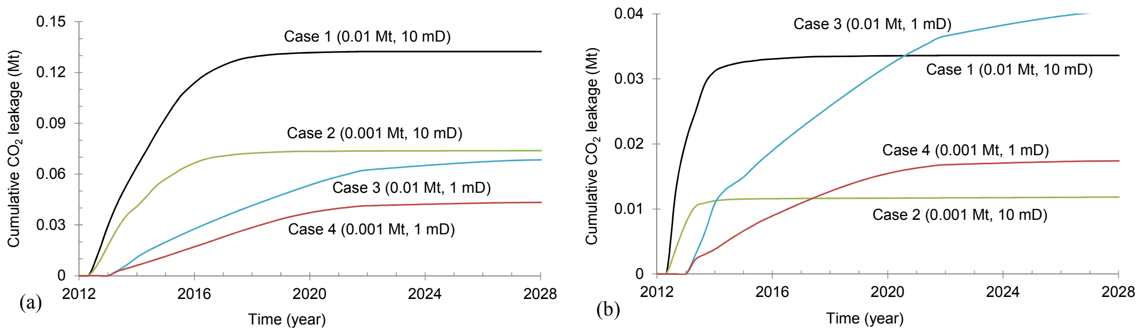


Fig.7. Profiles of cumulative CO_2 leakage for the four cases (a) unmitigated and (b)) reduced with 12 months of brine injection.

To start with, a much longer brine injection period (> 4 years) would be required for the remediation method to make a noticeable impact on leakage reduction, as illustrated in Fig. 8. For example, the results show that it would take 4 years of continuous brine injection to bring the leakage potential down to 0.35 Mt (a reduction of 0.11 Mt or 24%), and 10 years to 0.26 Mt (a reduction of 0.2 Mt or 43%). Examination of the two main factors driving the CO_2

leakage rate, i.e. the pressure differential between the two layers and the CO_2 saturation in the reservoir around the leakage block, reveals that there is an delay of up to 4 years from the start of injection in 2017 before a significant change in two parameters is observed.

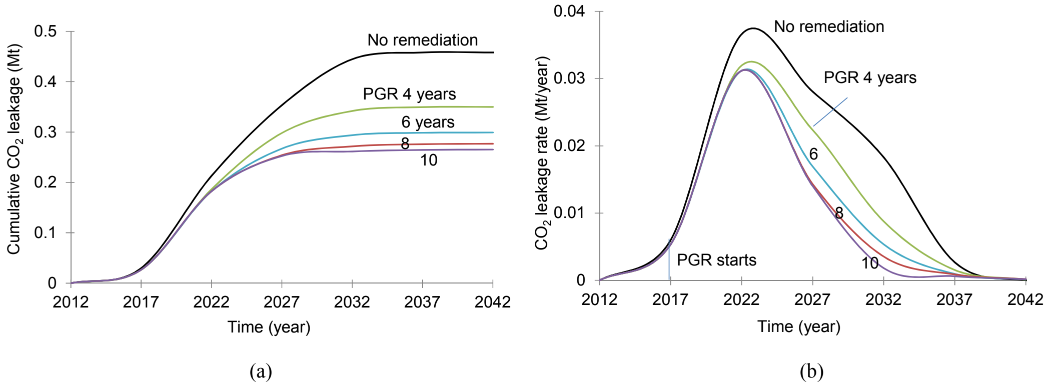


Fig.8.a) Cumulative CO_2 leakage and b) leakage rate for scenarios with different PGR times at P43 (Case 1).

4. Conclusions

The effectiveness of the pressure gradient reversal (PGR) method as a potential remediation technique for CO_2 leakage from deep saline aquifers is investigated using a generic 3D reservoir/caprock model. Two leakage locations (grid blocks P44 and P43) in the transient source region, at a distance of 200m and 1,200 m respectively, to the CO_2 injector were selected for conducting above-zone brine injection simulations. The brine injection simulation results indicate that the performance of PRG is strongly affected by how early leakage is detected from the start of injection (time-to-detection), which in turns is controlled by the detection threshold, leakage pathway permeability and the distance to the injection well. Specifically for the leakage scenarios considered in this study

- Above-zone brine injection not only brings down the pressure difference between the storage reservoir and the overlying permeable layer, as is intended, but also the CO_2 saturation in the reservoir around the leakage block. The reduction in CO_2 leakage potential is contributed to both the factors.
- The earlier a leakage is detected and the closer is the leakage location to the injection well, more effective PGR will be.

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